STATE OF CALIFORNIA
ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

Implementation of Renewables Portfolio Standard Legislation (Public Utilities Code Sections 381, 383.5, 399.11 through 399.15, and 445; [SB 1038], [SB 1078])	))))))	Docket No. 03-RPS-1078 RPS Proceeding

and

Implementation of Renewables Investment Plan Legislation (Public Utilities Code sections 381, 383.5, and 445 [SB 1038])	))))	Docket No. 02-REN-1038 Renewable Energy Program: Notice of Renewables Committee Workshop

re: **COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON RENEWABLES COMMITTEE'S REPORT ON THE CALIFORNIA RENEWABLES PORTFOLIO STANDARD RENEWABLE GENERATION INTEGRATION COST ANALYSIS, PHASE 1**

On February 20, 2004, the Renewables Committee of the California Energy Commission (the "Commission") held workshops on the proposed final report (the "Report") on the Analysis of Integration Costs of Intermittent Renewable Resources issued by the Commission's Renewables Committee (the "Committee"). The Report comprises the CEC Consultant's recommendations to the Committee on Phase I of the analysis for use in the Renewables Portfolio Standard ("RPS") proceeding. SCE has, as you know, participated in workshops on the development of the Report. On October 9, 2003, SCE submitted comments on a draft of the Report. Many of those comments are pertinent to the Report. SCE incorporates these comments herein. Southern California Edison Company ("Edison") appreciates the opportunity to file comments on the Report. At a workshop on February 20, 2004, SCE presented a summary of an analysis by Dr. Ed Kahn of the Analysis Group which took issue with several of the Report's conclusions. SCE provides Dr. Kahn's written comments herewith and asks the Commission take these comments into consideration.

As Dr. Kahn pointed out at the February 20 workshop, the Report is not based upon publicly available data. Therefore the process utilized by the Report to reach its conclusions is not transparent. More importantly, the results of the Report cannot be replicated. The Report's conclusions specifically with respect to the Effective Load Carrying Capacity ("ELCC") of wind generation facilities, as well as more generally those related to load following and regulation costs, are significantly at variance with SCE's experience.

For these and other reasons noted by Dr. Kahn and by SCE at the workshop and in prior comments, SCE believes that the Commission has failed to demonstrate the reliability of the Report. Unless and until the Report's conclusions can be established through a transparent and defensible process, it would be highly improper for the Report to be used in any authoritative respect for purposes of Renewable Portfolio Standard ("RPS") implementation and SCE fully reserves its rights to challenge use of the Report in any appropriate forum. SCE is willing to support further analysis of the ELCC of wind resources and other relevant issues and would be pleased to lend its support to the Committee. SCE urges the Committee to "get it right," and, accordingly, to delay issuance of the Report until its conclusions can be properly and adequately verified.

Southern California Edison Co.
Comments on California Renewables Portfolio Standard
Renewable Generation Integration Cost Analysis
Phase 1: One Year Analysis of Existing Resources
Results and Recommendations
Final Report
Dated: October 9, 2003

Introduction

Southern California Edison Co. is pleased to review the subject report and acknowledges the time and effort expended by its principle contributing parties:

- Oak Ridge National Laboratory;
- National Renewable Energy Laboratory;
- California ISO; and,
- California Wind Energy Collaborative

SCE finds numerous issues that are not dealt with in the report which raise many concerns about the validity of the results.

Discussion

With respect to imbalance costs, SCE was surprised with the result and assume you were also, given that it was so much lower than the estimates provided from other research efforts. For example, Brendan Kirby was a co-author on a joint paper delivered at a June 2003 wind conference. Table 6 from that paper summarizes the state of the art findings: SCE also noted the result shown in a paper presented by researchers in Denmark in 2001 at http://www.windpower.org/en/tour/wres/dkmap.htm

In that paper, the payment for "realtime imbalance power" is listed at DKK 65 million or DKK 0.02/kWh from 3372 GWh of wind. At 6.7 DKK/dollar, this is 2.9 mills/kWh. I note that it is unclear if this is the total system cost impact for this IOU due to wind power or a subset of the total cost picture.

Table 6. Summary of Study Results

Study and Relative Wind Penetration	Analytic (A) or Case Study (C)	Regulation	Load Following (L) or Imbalance (I)	Reserves	Unit Commit-ment	Allocation Method M=Market, I=Incremental O=ORNL	Cost $/MWh from Studied Time Scales
Hirst PJM 0.06%-0.12%	(A)	Y	I			M	$0.05-$0.30/MWh Regulation
Milligan IA up to 22.5%	(A)		L, I	(1)		O	(2)
UWIG / Electrotek Xcel 3.5%	(C)	Y	L, I (3)	Y	Y	I	$2.00/MWh
PacifiCorp IRP 20%	(C)		I	Y		I	$5.50/MWh
Hirst BPA 5.9%	(C)	Y	L, I		Y	O	$1.37-2.17/MWh

(1) Used 3 x standard deviation as indirect estimate of reserve requirements.
(2) Cost was not estimated in this study. Allocation of system variation (based on standard deviation) to wind ranged up to 2.5% of the wind rated capacity for load following and up to 4% for imbalance, for penetration rates up to 22.5% based on capacity.
(3) Imbalance energy costs determined from Unit Commitment production cost simulations.

SCE assumes that, given that the value shown in the report was almost 15 times smaller than this 2.9 mill value and well below any value presented in Table 6 for nontrivial penetration levels, it should be the cause for concern.

How has this inconsistency been addressed and confirmed the robustness of the result? If the 0.2 mills value is just the regulation component, is the report doing a disservice to ratepayers by ignoring 93% of the potential total imbalance costs associated with intermittent resources relative to non-intermittent resources?

With respect to ELCC, SCE noted that the ELCC for solar was 39% of nameplate (subsequently revised to 56.6%) and those for geothermal and biomass were much larger. Frankly, this result surprises us unless the solar data you used were based on a pure solar project (e.g., PV) and not a gas-assisted solar project. If it were supposed to be reflective of the latter, it fails a fundamental logic test. SCE's solar thermal units have over the past 10 years consistently realized close to 100% of their maximum capacity bonus payments. These payments are directly related to the plants' capacity factor in the summer on peak hours and reflect performance at or close to 100% capacity factor during summer onpeak hours. Insofar as your ELCC is supposed to reflect top load hours and insofar as most of Edison's top load hours occur in the summer on peak hours, then a 39% result for gas assisted solar is questionable.

In a prior discussion, SCE suggested that your ELCC calculations be done for each time of delivery period ("TOD") separately and then aggregated in proportion to the value associated with each such TOD period (or based on the % of top load hours in that TOD period). I also suggested that August and September needed to be differentiated from June and July, given that we have far more high load hours in August and September than in June and July. If you have not done this, then your solar number is too low and your wind number likely too high.

SCEs other question is if the data used for your calculations were aggregated data—that is, if all projects with a given fuel were combined together to produce the generation profile. I assume that you used aggregate data, for, if you did not, I would expect that you would have presented your results as ranges of value rather than a single value, reflecting likely local variations. If you did use aggregate data, I think it appropriate to keep in mind the goal here--to assist in a bid evaluation process in which we have to distinguish between adding a geothermal project or a wind project. In this context, I believe that the ELCC calculation must be TOD-weighted AND that it must reflect the output of a specific geothermal project or of a specific wind project, not the aggregate output of many wind projects or of many geothermal projects. Are you able to generate project-specific ELCC value ranges?

Finally, SCE has attempted on numerous occasions to validate the input data with the representatives of the CaISO. CaISO has been entirely unresponsive to SCEs repeated requests. SCE questions the validity of the input data since during the workshop in Sacramento on September 12, 2003, it was stated that the Geysers geothermal plants were utilized for the representative geothermal production profile; that none of the LUZ-SEGS facilities were utilized for the solar generation profile, and that 1200 MW of wind were utilized for the wind profiles, but that they were unable to specify which plants in which resource areas were included (SCE alone has over 1,000 MW of wind). The Geysers production profile is entirely unrepresentative for SCE's geothermal plants. The LUZSEGS plants are more representative of the likely future solar generation than any other solar facility. And it is unclear if the wind facilities that were utilized were in fact representative of SCE wind resource areas. As a result, one cannot be assured that the results are representative for the purpose that they are being prepared, specifically, to produce cost adders which can be added to a project's bid price during the bid selection process (see page xi).

Effective Load Carrying Capability of Wind Generation: Initial Results with Public Data*

E. Kahn
February 27, 2004

1. Introduction

With the rapidly growing interest in wind power generation and the simultaneous emergence of resource adequacy policies, it is natural to ask how to account for the value of wind generation from a capacity perspective. Resource adequacy requirements are one of a number of policy initiatives designed to assure the smooth functioning of wholesale electricity markets.[1] With adequate reserves, the vulnerability of electricity markets to market power is reduced. Resource adequacy policies typically mandate a reserve capacity requirement for Load Serving Entities (LSEs) over and above forecasted peak loads. These requirements may be met by contracts and/or residual capacity markets. Whatever the procurement mechanism, the product transacted is "capacity." Capacity for a given generating unit is typically measured by something like nameplate capacity that may or may not be adjusted by some reliability measure, such as one minus the forced outage rate of the unit in question.[2] This definition is designed to address the characteristics of thermal generation. It is not easily extended, however, to the characteristics of intermittent types of generation, such as wind power.

The purpose of this paper is to review recent work on how to measure the capacity value of wind generation and to demonstrate the principal sensitivities underlying calculations of this type. In Section 2 we discuss a useful concept from the power system engineering literature, effective load-carrying capability (ELCC), that has been applied to this problem. A recent study uses this concept in connection with wind generation in California (Kirby *et al.*, 2003). That study relies on confidential data for 2002 from the California Independent System Operator (CAISO). One purpose of this study is to replicate their work. This task is made more complex than it would otherwise be since any replication must rely on public data.[3] Section 3 discusses the use of public data for estimating ELCC in California. While an enormous amount of data on the California

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* This work was supported by Southern California Edison Company. I appreciate comments from Gary Allen, Richard Davis and Mark Minick. Excellent research assistance has been provided by Matt Barmack, Edo Macan, Alex Hirsch and Dan Steinert.

[1] See CPUC (2004) for a recent discussion of resource adequacy policy in California.

[2] See, for example, PJM Interconnection (2000) Schedule 7 or NYISO (2002) Attachment J where the forced outage adjustment is discussed.

[3] One stated goal of Kirby *et al.* is transparent analysis based on input data and tools in the public domain (see Section 1.3). The use of confidential data from the CAISO is not consistent with that goal.

market has become available publicly in connection with FERC investigations, it is not sufficient to reproduce the calculations discussed in Kirby *et al*. Therefore, replication efforts must rely on publicly available data. Section 4 presents initial results. Section 5 discusses a number of sensitivity tests. Finally, in Section 6 we outline the types of analyses that will be useful in forming policy decisions on this issue.

2. Effective Load Carrying Capability

Not all thermal units have equal impacts on power system reliability. Large units with high forced outage rates have a disproportionately negative impact on system reliability.[4] To measure these effects, power system engineers have developed reliability indices and applied them to making marginal assessments of new capacity additions. The literature on reliability measurement goes back more than 50 years. Probability methods were introduced in the late 1940s (Calabresse, 1947). An index known as the "loss of load probability" was developed that measures the number of days per year of expected capacity shortages. Strictly speaking, the annual index is an expectation, not a probability, so the correct name for the index is Loss of Load Expectation (LOLE). Formally, we can define the probability that in a given hour available capacity is less than load. We call this the LOLP for hour i, or $LOLP_i$

$$LOLP_i = \Pr\left(\sum C_j < L_i\right), \qquad (1)$$

where C_j is the random variable representing the capacity of generator j in hour i and L_i is the load in hour i. The annual LOLE index is defined over all hours of the year i as

$$LOLE = \sum LOLP_i. \qquad (2)$$

The "one day in ten years" criterion, commonly cited as a planning objective for LOLE, means that LOLE should be 2.4 hours in each year.

Garver (1966) defined the effective load carrying capacity (ELCC) as the amount of new load, call it ΔL, that can be added to a system at the initial LOLE, which we call $LOLE_I$, after a new unit with capacity ΔC_{max} is added. If we denote the random variable representing the available capacity of ΔC_{max} by ΔC, then solving (3) for ΔL gives an implicit definition of ELCC.

$$LOLE_I = \sum \Pr\left(\sum C_j + \Delta C < L_i + \Delta L\right) \qquad (3)$$

[4] Lyons (1979) and Deb and Mulvaney (1982) are examples of studies in which such effects are taken into account.

It is often convenient to express ELCC in normalized form, i.e. as a percentage of rated capacity,

$$\text{ELCC} = \Delta L / \Delta C_{max} \qquad (4)$$

Calculating LOLP involves the convolution of the probability distribution functions characterizing the availability of each generator. Methods for convolution are described in Stoll (1989) Chapter 10. Typically, the random availability of thermal generators is represented as a two-state function parameterized by the forced outage rate (FOR). The available capacity is zero with probability equal to the FOR and full capacity with probability equal to 1 – FOR. This is the procedure that we adopt below. There are more complex representations of the random availability of generators, but data are not commonly available to use these. Conversely, generation resources may also be treated deterministically. In our analysis we treat hydro generation and imports, which are important resources in the CAISO control area, deterministically. While we do not know what approach Kirby *et al.* take to characterizing the availability of hydro and imports, we assume that they treat them deterministically.[5]

Finally, ELCC has typically been calculated on a single area basis. This means that no representation of transmission constraints is incorporated into the analysis.

3. Public Data Issues

Kirby *et al.* analyze data for the calendar year 2002. They obtained most of their data from the CAISO. While the CAISO makes a certain amount of these data public, in particular, hourly loads and imports, other data involving generation inside California are not public. For thermal generation inside California, lack of hourly output data is not a problem, because LOLE treats these resources probabilistically.[6] For hydro production, however, lack of hourly data is an issue. As a proxy for the hydro data for 2002, we will use hourly hydro data from 2000. These data are publicly available as a result of FERC proceedings.[7] How we use the hourly hydro data is the first topic discussed below. An

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[5] Maintenance schedules are another element that is sometimes incorporated into LOLE studies. Kirby *et al.* choose not to include them, and we adopt that convention as well. If maintenance scheduling were optimal, it would not affect LOLE since all of the maintenance outage would occur in low LOLP hours. Sub-optimal maintenance scheduling can affect LOLE.

[6] For thermal generators, Kirby *et al.* use a commercial database to obtain FOR values. Our analysis also relies on such a database, but a different one.

[7] Disaggregated hourly metered generation data for every resource inside the CAISO control area, including hydro resources, were released by FERC in connection with both the Refund Case (Docket No. EL00-95 and related dockets) and the Western Markets Investigation (Docket No. PA2-02). The Refund Case data were produced as part of one of the California Parties' exhibits (CA-270) and are available from FERC's eLibrary (http://ferris.ferc.gov/idmws/search/intermediate.asp?link_file=yes&doclist=4083779). The Western Markets data are available at http://ferc.aspensys.com/FercData/Miscellaneous%20cd's/Box082/ and http://ferc.aspensys.com/FercData/Miscellaneous%20cd's/CAISO-881/.

additional related issue involves the separation of the Sacramento Municipal Utility District (SMUD) from the CAISO control area in June 2002.

Hydro

The fundamental building block of ELCC is the hourly LOLP. This function is nearly exponential in load (Levy and Kahn, 1982). This means that the vast majority of load hours contribute very little to the LOLE. Conversely, the highest load hours contribute the vast majority of the LOLE. We treat hydro generation as a deterministic input to LOLP.[8] This assumption means that LOLP is also essentially exponential in hydro output. Therefore hourly changes in hydro can have significant effects on LOLE.

There is over 11,000 MW of hydro generation capacity in the CAISO control area. The maximum production during high load periods is substantially less. Joskow and Kahn (2002), relying on public data sources available before FERC released detailed data, use 8500 MW as the maximum high load production. This estimate was based on CAISO data from 2001. The hourly data released in 2003 show that the year 2000 maximum output was 8949 MW. When analyzing the top 50 hydro production hours, it was determined that the generation output declined to 8482 MW in the 50th highest production hour.

Total hydro energy production in California was lower in 2002 than in 2000. Table 1 below shows data on hydro generation in the summer months for the period 1998 to 2003 (EIA, 2003). These data show anywhere from 15% to 33% less hydro energy per month in Summer 2002 than in Summer 2000. For our purposes, however, what matters is the maximum hydro output levels in the distinct high load (LOLP) hours. The CAISO's analysis of the year 2001 hydro production suggests that maximum output was not affected by the lower energy generation in that year compared to 2000 (CAISO, 2002). This is clear, for example, from Table I-1 in CAISO, 2002. This table calculates the components of total capacity available to the CAISO. It shows "hydro limitations" of 2000 MW, i.e. that not all of the installed hydro capacity is available to meet peak demands. This derate from the 11,000 MW of hydro leaves about 9000 MW available to meet load, which is roughly what the year 2000 data show

Table 1. Hydro Generation in California (GWh)

	June	July	August
1998	5,280	5,130	4,753
1999	4,074	4,134	3,648
2000	4,419	4,216	3,696
2001	3,064	2,985	2,913
2002	3,449	3,273	3,065
2003	4,151	4,000	3,405

[8] Typical values for the FOR of hydro units are on the order of 1%. This is virtually the same as the deterministic assumption that the hydro FOR is zero.

Because we do not have the hourly hydro data for 2002, we must make some assumptions about how the hydro generation would have been dispatched. We adopt a natural approach which matches the maximum hydro output to the maximum loads in a monotonically descending order. That is, we take the highest hourly load and assign the highest hourly hydro output, the second highest load is assigned the second highest hydro output, etc. This approach might be called perfect load shaving, in the sense that we are assuming sufficient knowledge for the matching to occur. It is a computationally obvious procedure, and may well be a good approximation since most storage hydro resources are used for serving load in the highest hours. We discuss this issue further below.

SMUD

The Sacramento Municipal Utility District is a geographic island within the CAISO's NP15 zone, i.e. all SMUD interconnections are within NP15. SMUD operations have historically been closely integrated with those of other systems in Northern California. SMUD has hydro resources on the Upper American River and thermal generation in its service territory. The sum of the generation is substantially less than the SMUD peak load. SMUD meets its remaining load using imports. Before SMUD began operating as its own control area, its loads and resources were part of NP15, as were the imports needed to serve its loads.

Since we are using the 2000 hydro data for our 2002 analysis, we would like to remove the SMUD hydro (and thermal) resources from the supply mix. While it is easy to identify and remove the thermal units, there are no identifiers for SMUD's hydro in the public data. We can, however, account for SMUD's absence from the CAISO control area after June 2002 by another mechanism. We add SMUD's hourly loads[9] to those of the CAISO and we leave SMUD's thermal resources in the supply mix. We already have SMUD's hydro resources in our aggregated hydro representation. The remaining issue involves accounting for the CAISO exports to SMUD. These can be read off the CAISO website.[10] The precise accounting mechanism is to add the CAISO exports to SMUD back into the CAISO net imports. CAISO net imports are simply gross imports minus gross exports. Since all SMUD's imports must go through the CAISO control area, the correct measure of imports for our calculation including SMUD loads and resources is CAISO net imports plus CAISO exports to SMUD.

New Resources

New generation resources came on line in 2002. Table 2 shows the projects in question, their capacity and the dates on which they became operational. The data in this table are based on the Henwood Energy Services Inc. (HESI) database, which we also use for forced outage rate estimates. There may be slight differences in the dates at which particular projects are deemed to be operational. There is some inherent ambiguity in the

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[9] These are available from FERC Form 714.

[10] See http://oasis.caiso.com/ The imports posted here include day-ahead and hour-ahead schedules, but not any real time imports. We use hour-ahead schedules for imports.

whole notion of an operational date. What exactly constitutes initial operation? What are the criteria? Who makes this decision? Is there a uniform process?

Different determinations of initial operation can have an impact on hourly LOLP results if the projects in question are sufficiently large. The obvious examples in Table 2, where ambiguity about commercial operation date might matter, are the Delta Energy Center, Moss Landing Combined Cycle and La Paloma projects. For our calculations, we use the data in Table 2, which means that these units are included only on or after the Operational Dates given there.

Table 2. New Capacity On Line Dates

Unit	Capacity (MW)	Operational Date
Midsun 1	19	1/23/2002
Calpine Gilroy GT3	45	2/13/2002
Redding CC 1	68	6/1/2002
CalPeak El Cajon 1	49	6/15/2002
Delta Energy Center	826	6/17/2002
CalPeak Vaca-Dixon 1	48	7/1/2002
Moss Landing CC 1-2	1,008	7/1/2002
Henrietta	92	7/1/2002
Dinuba 1	11	7/5/2002
Yuba City Peaker 1	49	7/12/2002
Capitol Power 1	12	7/15/2002
La Paloma 1a	262	7/26/2002
Huntington Beach 3	205	8/1/2002
Whitewater Hill 1	18	8/31/2002
La Paloma 1b	262	9/22/2002
La Paloma 2a	262	10/15/2002
La Paloma 2b	262	11/15/2002
SDSU Cogen 1	13	12/1/2002
Creed 1	45	12/15/2002
Goosehaven 1	45	12/15/2002
Lambie 1	45	12/15/2002
Feather River Energy 1	45	12/31/2002

4. Initial Results

In this section we briefly describe the wind data that we use and present our Base Case results.

We obtained hourly wind production data from Southern California Edison for the roughly 1000 MW of rated capacity in their service territory. Table 3 shows average output levels for 2000-2003 at three grid locations.[11] The roughly 30% capacity factor in

[11] Kirby *et al.* distinguish between the Tehachapi and San Gorgonio wind regions. San Gorgonio is identical to the Devers grid location in Table 2. Tehachapi may include both Antelope and Vincent, but that is not clear.

Table 3 is consistent with data in Kirby *et al.,* in particular Figures 3.16 and 3.17. The Table 3 data show that geographic variability is greater than aggregate variability. We will work with the aggregate of all three locations. Working with the aggregate should give an upward bias to the ELCC compared with using more disaggregated data.

Table 3. Wind Generation (Average kW/yr)

	Antelope	Devers	Vincent	Total
2000	92,591	108,437	90,575	291,603
2001	90,734	98,006	82,682	271,422
2002	97,077	110,249	88,367	295,693
2003	107,550	100,473	82,923	290,946

Figure 1 shows a plot of the top 100 LOLP hours and the corresponding wind generation. This figure shows the rapid decay of hourly LOLP and the substantial output fluctuation of Southern California wind generation. The ELCC for the Base Case is 13%. The LOLE for the Base Case is 0.159 hours. Figure 1 gives some intuition about the low value of ELCC. Low wind output at the times of high demand is the fundamental issue. While there are hours in the top 20 when wind output is relatively high, the wind output is less than 100 MW in half of these hours, including those with the highest hourly LOLPs.

Figure 1. Top 100 Ranked LOLPs vs. Wind Generation (2002)

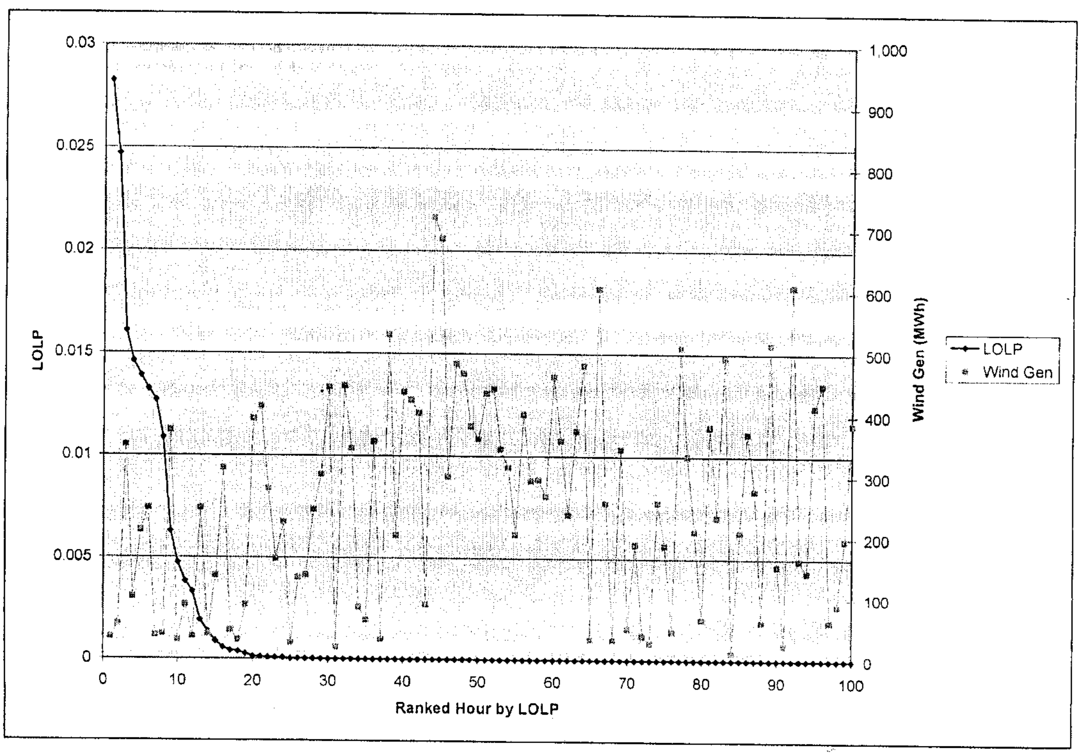

Table 4 gives the same data for the top 20 hours along with load, hydro generation, imports and the hourly LOLP values before and after the ELCC calculation. The fluctuations in hourly imports illustrated in this table shows how the rank order of high loads and high LOLP hours may be less than perfectly correlated. In Table 4, the "target LOLP" is the hourly LOLP before adding incremental wind generation and incremental load for the ELCC calculation. The "final LOLP" is the hourly LOLP after adding incremental wind generation and incremental load. The column labeled "wind" is the observed aggregate wind generation in each hour. For our ELCC tests the incremental wind is 20% of the observed wind generation to each hour.

Both Table 4 and Fig. 1 can be interpreted in terms of ELCC as follows. The fluctuating wind generation in the top LOLP hours can be thought of as weighted by the hourly LOLPs. Low capacity factor in high LOLP hours dominates higher capacity factor in lower LOLP hours. Our results show that only the top 20 hours matter in this weighting process; i.e. they contain more that 95% of the LOLE. This seems to contrast with the results of Kirby *et al.* In their Figure 3.1, it appears that the top 50 hours contain the bulk of the LOLE. It is unclear why our results differ. Inspection of Figure 1 shows that if LOLE did involve the top 50 hours, ELCC would be higher in that case than if only the top 20 hours were involved. This is clear from the upward trend in average capacity factor. Figures 3.16 and 3.17 in Kirby *et al.* also show an increase in average capacity factor as the number of hours averaged goes up from zero.

Table 4. Base Case Results: Top 20 LOLP Hours

date	hour	target lolp	final lolp	load	base system cap	hydro	imports	wind
7/10/2002	15	0.028286	0.029250	44,961	34,652	8,949	6,847	36
7/9/2002	15	0.024704	0.025377	43,820	34,652	8,772	5,938	57
7/12/2002	16	0.016086	0.014800	43,076	34,701	8,738	5,119	351
7/9/2002	16	0.014604	0.014771	43,997	34,652	8,805	6,322	101
7/9/2002	17	0.013896	0.013476	43,919	34,652	8,774	6,191	211
7/12/2002	15	0.013246	0.012671	42,868	34,701	8,707	5,148	247
7/10/2002	14	0.012719	0.013169	44,077	34,652	8,835	6,506	39
7/9/2002	14	0.010885	0.011276	42,760	34,652	8,680	5,422	41
7/12/2002	17	0.006285	0.005678	42,687	34,701	8,680	5,240	375
7/10/2002	13	0.004752	0.004956	42,511	34,652	8,665	5,605	31
7/12/2002	14	0.003808	0.003874	42,029	34,701	8,619	5,168	88
7/10/2002	16	0.003281	0.003419	44,108	34,652	8,884	7,150	37
7/9/2002	18	0.001885	0.001789	42,823	34,652	8,703	6,086	247
7/9/2002	13	0.001316	0.001372	41,298	34,652	8,548	5,079	41
7/10/2002	17	0.000879	0.000877	43,595	34,652	8,760	7,240	137
7/10/2002	18	0.000567	0.000518	43,033	34,652	8,727	6,717	313
7/12/2002	13	0.000417	0.000435	40,615	34,701	8,417	4,952	47
7/11/2002	15	0.000373	0.000392	41,740	34,652	8,583	6,020	31
7/11/2002	16	0.000269	0.000274	42,126	34,652	8,623	6,439	88
7/10/2002	19	0.000124	0.000108	41,861	34,652	8,605	6,184	394

5. Sensitivity Tests

In this section we report the results of some sensitivity tests. We consider three factors. First we examine the effect of lower forced outage rates for gas-fired generation. Second, we consider an alternative hydro dispatch which assumes less foresight than in the Base Case. Finally, we run our tests on 2003 data to see how results vary with a different profile of wind generation and further resource additions.

Forced Outage Rates

Over time the ISO generation system will become more reliable on average. Older units, with high forced outage rates in the HESI database will be retired and new units will come into service. Additionally, resource adequacy obligations are likely to result in lower LOLE levels. For the purpose of a quick test, we set all forced outage rates for gas-fired generators to 5% as a way to examine the sensitivity of ELCC to greater generation system reliability. The average FOR for gas-fired units in the 2002 cases was 7.4%.

Hydro Dispatch

Our Base Case hydro dispatch assumes perfect foresight. While computationally simple, perfect foresight is a very strong behavioral assumption. As an alternative, we test what we call "equivalent foresight." We look at the 2000 hourly loads and hydro dispatch. We rank the loads in monotonically descending order, matching the hydro dispatch in each hour with the corresponding load. For 2002 we assign to the i^{th} ranked load the hydro dispatch of the i^{th} ranked load in 2000. This procedure assumes that whatever degree of foresight was achieved in 2000 with respect to matching hydro dispatch to loads was also achieved in 2002.

2003 Data

Our results show that in 2003, wind generation was more coincident with high LOLP hours than in 2002. We cannot implement exactly the same procedure for the 2003 analysis that we used for 2002. The main difference is that the hourly load data for SMUD are not yet available. For simplicity we developed a load multiplier from the 2002 data which we apply to the 2003 CAISO loads.

Results

Table 5 summarizes results. It shows that imperfect hydro dispatch increases LOLE. For the 2002 data, this increases ELCC, but slightly reduces it in 2003. The forced outage rate tests result in lower LOLE, and usually a slight reduction in ELCC. Both of these effects are small in comparison to the difference in wind generation between 2002 and 2003.

Table 5. Sensitivity Cases

Year	Outage Rate	Hydro Dispatch	LOLE	ELCC
2002	base	Perfect	0.15924	13.0%
2002	base	Imperfect	0.27262	14.0%
2002	5%	Perfect	0.00055	11.5%
2002	5%	Imperfect	0.00139	15.0%
2003	base	Perfect	4.68E-05	21.5%
2003	base	Imperfect	0.00023	20.5%
2003	5%	Perfect	8.91E-09	21.5%
2003	5%	Imperfect	9.58E-08	21.0%

Detailed results are provided in Appendix A.

6. Next Steps

The Kirby *et al.* results are not replicable with the procedures we have outlined. We find lower ELCC using the 2002 data, resulting primarily from a more concentrated distribution of high LOLP hours (20 vs. 50). The 2003 wind data shows better coincidence of wind generation with the high LOLP hours, but the distribution of LOLP hours is still concentrated in 20 hours.

Before adopting policies based on the Kirby *et al.* results, it would be useful to understand better how they were obtained. One possibility that has not been examined numerically is that the use of distributions for wind energy output, rather than just the actually observed hourly output, explains some of the observed differences in results. This topic is discussed in Section 3.2.3 of Kirby *et al.*, but in a manner that is not sufficiently clear for testing.

Finally, there are a number of policy implications that arise from this investigation. How should modeling differences be resolved? Modeling differences have been at the center of disputes involving QF pricing, for example. The resolution of these differences in California required extensive effort (Kahn, 1995). Will such efforts be made in this case? Should the application of ELCC methods be similar in all procurement contexts? Does bid evaluation differ from resource adequacy accounting? Resource adequacy requirements are likely to result in payments to generators for capacity. What policy is appropriate to pay wind generators for capacity given the variability in ELCC as a function of wind/load coincidence? In all likelihood a more substantial dialogue on these questions will be necessary before a workable consensus emerges.

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Appendix A: Detailed Results

Table A-1. Imperfect Hydro Dispatch 2002: Top 40 Hours

date	hour	target lolp	final lolp	load	base system cap	hydro	imports	wind
7/12/2002	16	0.055300	0.051668	43,076	34,701	8,032	5,119	351
7/10/2002	15	0.054415	0.056285	44,961	34,652	8,562	6,847	36
7/9/2002	15	0.024704	0.025468	43,820	34,652	8,772	5,938	57
7/9/2002	16	0.019423	0.019712	43,997	34,652	8,653	6,322	101
7/10/2002	14	0.018304	0.018996	44,077	34,652	8,643	6,506	39
7/12/2002	14	0.016269	0.016578	42,029	34,701	7,899	5,168	88
7/12/2002	15	0.015490	0.014885	42,868	34,701	8,625	5,148	247
7/9/2002	14	0.013790	0.014328	42,760	34,652	8,558	5,422	41
7/9/2002	17	0.013093	0.012744	43,919	34,652	8,805	6,191	211
7/9/2002	13	0.010548	0.010971	41,298	34,652	7,577	5,079	41
7/10/2002	13	0.007995	0.008358	42,511	34,652	8,413	5,605	31
7/12/2002	17	0.005413	0.004905	42,687	34,701	8,752	5,240	375
7/10/2002	17	0.005390	0.005401	43,595	34,652	7,948	7,240	137
7/10/2002	16	0.003281	0.003433	44,108	34,652	8,884	7,150	37
7/11/2002	15	0.002276	0.002391	41,740	34,652	7,818	6,020	31
7/10/2002	18	0.001919	0.001773	43,033	34,652	8,208	6,717	313
7/9/2002	18	0.001741	0.001660	42,823	34,652	8,738	6,086	247
7/10/2002	12	0.000385	0.000408	40,889	34,652	7,621	6,122	27
7/11/2002	16	0.000306	0.000314	42,126	34,652	8,572	6,439	88
8/12/2002	17	0.000306	0.000262	42,827	35,180	7,608	7,255	447
7/10/2002	19	0.000229	0.000201	41,861	34,652	8,370	6,184	394
7/8/2002	16	0.000170	0.000171	40,188	34,652	7,747	5,509	134
7/8/2002	18	0.000144	0.000132	39,365	34,652	7,016	5,316	300
7/12/2002	18	0.000132	0.000114	41,280	34,701	8,482	5,635	414
7/9/2002	19	0.000121	0.000112	41,377	34,652	8,452	5,979	279
7/12/2002	13	0.000106	0.000112	40,615	34,701	8,949	4,952	47
7/18/2002	14	9.88E-05	9.88E-05	37,263	34,713	7,059	3,415	138
7/18/2002	16	9.00E-05	8.23E-05	37,968	34,713	7,229	3,820	303
7/18/2002	15	8.57E-05	8.19E-05	37,900	34,713	7,634	3,443	225
7/22/2002	16	8.39E-05	8.37E-05	36,450	34,713	5,442	4,274	144
7/10/2002	11	8.09E-05	8.56E-05	39,642	34,652	6,818	6,274	33
7/11/2002	17	7.83E-05	7.72E-05	41,763	34,652	8,601	6,492	165
6/6/2002	14	5.29E-05	4.85E-05	38,981	32,628	6,989	7,228	295
7/18/2002	17	5.23E-05	4.47E-05	37,675	34,713	6,881	3,953	425
7/9/2002	12	4.30E-05	4.56E-05	39,727	34,652	7,753	5,655	33
7/19/2002	16	3.94E-05	3.40E-05	38,546	34,713	7,283	4,545	404
6/6/2002	18	3.73E-05	2.97E-05	37,712	32,628	5,852	6,971	545
8/14/2002	17	3.58E-05	2.59E-05	40,690	35,180	7,849	5,409	722
6/25/2002	16	3.23E-05	2.85E-05	38,611	33,493	7,223	5,928	362
6/6/2002	13	3.09E-05	2.95E-05	37,976	32,628	6,189	7,292	218

Figure A-1. 2003 Top 100 Hours Perfect Hydro Dispatch

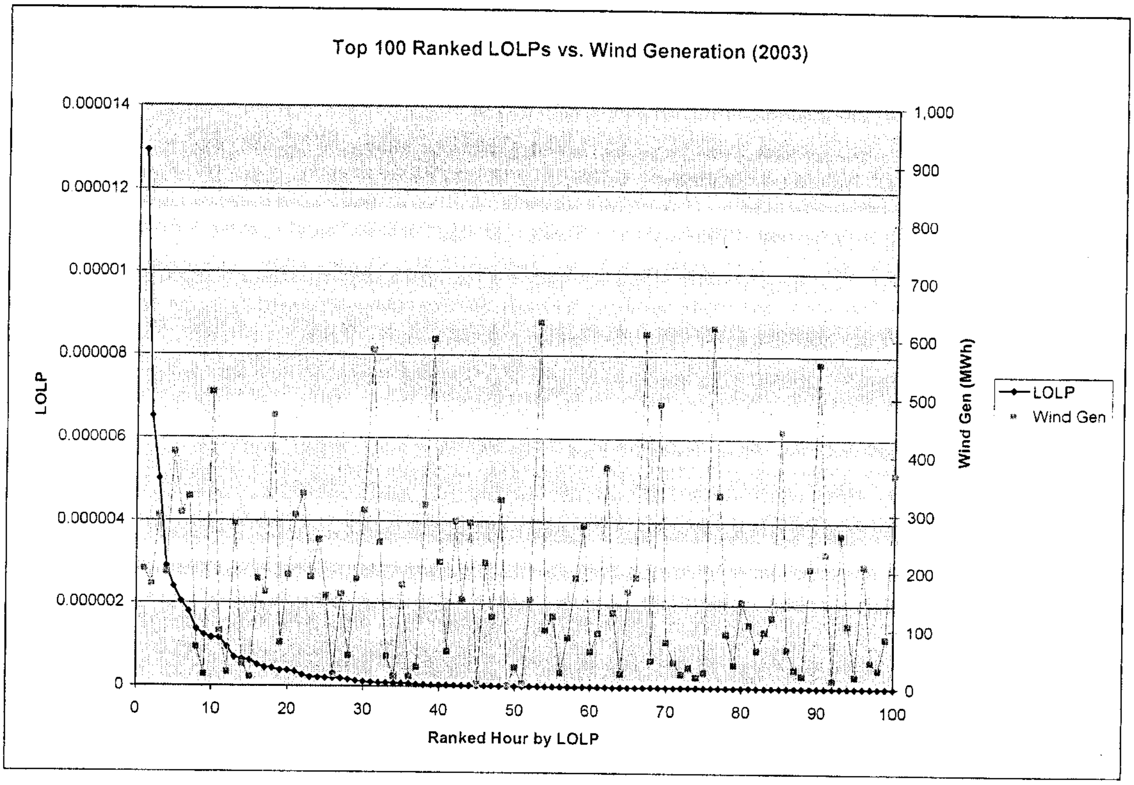

Table A-2. Perfect Hydro Dispatch 2002: Top 40 Hours

date	hour	target lolp	final lolp	load	base system cap	hydro	imports	wind
7/10/2002	15	0.028286	0.029250	44,961	34,652	8,949	6,847	36
7/9/2002	15	0.024704	0.025377	43,820	34,652	8,772	5,938	57
7/12/2002	16	0.016086	0.014800	43,076	34,701	8,738	5,119	351
7/9/2002	16	0.014604	0.014771	43,997	34,652	8,805	6,322	101
7/9/2002	17	0.013896	0.013476	43,919	34,652	8,774	6,191	211
7/12/2002	15	0.013246	0.012671	42,868	34,701	8,707	5,148	247
7/10/2002	14	0.012719	0.013169	44,077	34,652	8,835	6,506	39
7/9/2002	14	0.010885	0.011276	42,760	34,652	8,680	5,422	41
7/12/2002	17	0.006285	0.005678	42,687	34,701	8,680	5,240	375
7/10/2002	13	0.004752	0.004956	42,511	34,652	8,665	5,605	31
7/12/2002	14	0.003808	0.003874	42,029	34,701	8,619	5,168	88
7/10/2002	16	0.003281	0.003419	44,108	34,652	8,884	7,150	37
7/9/2002	18	0.001885	0.001789	42,823	34,652	8,703	6,086	247
7/9/2002	13	0.001316	0.001372	41,298	34,652	8,548	5,079	41
7/10/2002	17	0.000879	0.000877	43,595	34,652	8,760	7,240	137
7/10/2002	18	0.000567	0.000518	43,033	34,652	8,727	6,717	313
7/12/2002	13	0.000417	0.000435	40,615	34,701	8,417	4,952	47
7/11/2002	15	0.000373	0.000392	41,740	34,652	8,583	6,020	31
7/11/2002	16	0.000269	0.000274	42,126	34,652	8,623	6,439	88
7/10/2002	19	0.000124	0.000108	41,861	34,652	8,605	6,184	394
7/12/2002	18	0.000114	9.81E-05	41,280	34,701	8,537	5,635	414
7/9/2002	19	9.10E-05	8.40E-05	41,377	34,652	8,558	5,979	279
7/11/2002	17	8.04E-05	7.89E-05	41,763	34,652	8,591	6,492	165
7/18/2002	15	7.86E-05	7.47E-05	37,900	34,713	7,666	3,443	225
7/10/2002	12	3.94E-05	4.18E-05	40,889	34,652	8,485	6,122	27
7/8/2002	16	3.77E-05	3.76E-05	40,188	34,652	8,306	5,509	134
7/18/2002	14	3.34E-05	3.32E-05	37,263	34,713	7,455	3,415	138
7/8/2002	17	2.75E-05	2.57E-05	40,253	34,652	8,313	5,569	245
7/18/2002	16	2.47E-05	2.24E-05	37,968	34,713	7,697	3,820	303
8/13/2002	16	2.08E-05	1.73E-05	42,168	35,180	8,625	6,581	445
7/11/2002	14	1.96E-05	2.09E-05	41,086	34,652	8,502	6,556	20
8/12/2002	17	1.56E-05	1.30E-05	42,827	35,180	8,707	7,255	447
8/12/2002	16	1.43E-05	1.26E-05	43,014	35,180	8,720	7,562	346
7/12/2002	12	1.19E-05	1.22E-05	39,446	34,701	8,141	5,338	85
7/8/2002	15	1.18E-05	1.23E-05	39,594	34,652	8,170	5,527	64
7/9/2002	20	1.18E-05	1.03E-05	39,820	34,652	8,224	5,407	357
7/9/2002	12	1.14E-05	1.21E-05	39,727	34,652	8,218	5,655	33
8/13/2002	17	1.07E-05	8.43E-06	41,820	35,180	8,603	6,399	531
7/11/2002	18	1.05E-05	1.00E-05	40,889	34,652	8,482	6,411	204
7/10/2002	20	9.07E-06	7.54E-06	40,568	34,652	8,413	5,974	438

Table A-3. Imperfect Hydro Dispatch 2002: Top 40 Hours
Forced Outage Rate Set to 5 Percent

date	hour	target lolp	final lolp	load	base system cap	hydro	imports	wind
7/12/2002	16	0.000436	0.000390	43,076	34,701	8,032	5,119	351
7/10/2002	15	0.000422	0.000450	44,961	34,652	8,562	6,847	36
7/9/2002	15	0.000113	0.000119	43,820	34,652	8,772	5,938	57
7/9/2002	16	7.60E-05	7.83E-05	43,997	34,652	8,653	6,322	101
7/10/2002	14	6.90E-05	7.37E-05	44,077	34,652	8,643	6,506	39
7/12/2002	14	5.73E-05	5.94E-05	42,029	34,701	7,899	5,168	88
7/12/2002	15	5.29E-05	5.00E-05	42,868	34,701	8,625	5,148	247
7/9/2002	14	4.37E-05	4.68E-05	42,760	34,652	8,558	5,422	41
7/9/2002	17	4.02E-05	3.88E-05	43,919	34,652	8,805	6,191	211
7/9/2002	13	2.85E-05	3.05E-05	41,298	34,652	7,577	5,079	41
7/10/2002	13	1.84E-05	1.98E-05	42,511	34,652	8,413	5,605	31
7/12/2002	17	1.00E-05	8.65E-06	42,687	34,701	8,752	5,240	375
7/10/2002	17	9.90E-06	1.00E-05	43,595	34,652	7,948	7,240	137
7/10/2002	16	4.58E-06	4.95E-06	44,108	34,652	8,884	7,150	37
7/11/2002	15	2.61E-06	2.83E-06	41,740	34,652	7,818	6,020	31
7/10/2002	18	2.01E-06	1.79E-06	43,033	34,652	8,208	6,717	313
7/9/2002	18	1.73E-06	1.62E-06	42,823	34,652	8,738	6,086	247
7/10/2002	12	1.77E-07	1.94E-07	40,889	34,652	7,621	6,122	27
8/12/2002	17	1.26E-07	1.00E-07	42,827	35,180	7,608	7,255	447
7/11/2002	16	1.25E-07	1.31E-07	42,126	34,652	8,572	6,439	88
7/10/2002	19	8.10E-08	6.71E-08	41,861	34,652	8,370	6,184	394
7/8/2002	16	5.20E-08	5.26E-08	40,188	34,652	7,747	5,509	134
7/8/2002	18	4.04E-08	3.59E-08	39,365	34,652	7,016	5,316	300
7/12/2002	18	3.58E-08	2.91E-08	41,280	34,701	8,482	5,635	414
7/9/2002	19	3.11E-08	2.81E-08	41,377	34,652	8,452	5,979	279
7/12/2002	13	2.59E-08	2.82E-08	40,615	34,701	8,949	4,952	47
7/18/2002	14	2.33E-08	2.34E-08	37,263	34,713	7,059	3,415	138
7/18/2002	16	2.02E-08	1.79E-08	37,968	34,713	7,229	3,820	303
7/18/2002	15	1.88E-08	1.77E-08	37,900	34,713	7,634	3,443	225
7/22/2002	16	1.82E-08	1.83E-08	36,450	34,713	5,442	4,274	144
7/10/2002	11	1.72E-08	1.88E-08	39,642	34,652	6,818	6,274	33
7/11/2002	17	1.63E-08	1.61E-08	41,763	34,652	8,601	6,492	165
7/18/2002	17	9.02E-09	7.20E-09	37,675	34,713	6,881	3,953	425
6/6/2002	14	8.00E-09	7.09E-09	38,981	32,628	6,989	7,228	295
7/9/2002	12	6.71E-09	7.37E-09	39,727	34,652	7,753	5,655	33
7/19/2002	16	5.93E-09	4.80E-09	38,546	34,713	7,283	4,545	404
8/14/2002	17	5.16E-09	3.21E-09	40,690	35,180	7,849	5,409	722
6/6/2002	18	4.75E-09	3.40E-09	37,712	32,628	5,852	6,971	545
6/25/2002	16	4.06E-09	3.40E-09	38,611	33,493	7,223	5,928	362
7/11/2002	14	3.93E-09	4.38E-09	41,086	34,652	8,353	6,556	20

Table A-4. Perfect Hydro Dispatch 2002: Top 40 Hours
Forced Outage Rate Set to 5 Percent

date	hour	target lolp	final lolp	load	base system cap	hydro	imports	wind
7/10/2002	15	0.000141	0.000147	44,961	34,652	8,949	6,847	36
7/9/2002	15	0.000113	0.000117	43,820	34,652	8,772	5,938	57
7/12/2002	16	5.63E-05	4.88E-05	43,076	34,701	8,738	5,119	351
7/9/2002	16	4.79E-05	4.84E-05	43,997	34,652	8,805	6,322	101
7/9/2002	17	4.43E-05	4.17E-05	43,919	34,652	8,774	6,191	211
7/12/2002	15	4.12E-05	3.80E-05	42,868	34,701	8,707	5,148	247
7/10/2002	14	3.84E-05	4.02E-05	44,077	34,652	8,835	6,506	39
7/9/2002	14	3.00E-05	3.14E-05	42,760	34,652	8,680	5,422	41
7/12/2002	17	1.27E-05	1.07E-05	42,687	34,701	8,680	5,240	375
7/10/2002	13	8.14E-06	8.60E-06	42,511	34,652	8,665	5,605	31
7/12/2002	14	5.80E-06	5.90E-06	42,029	34,701	8,619	5,168	88
7/10/2002	16	4.58E-06	4.83E-06	44,108	34,652	8,884	7,150	37
7/9/2002	18	1.96E-06	1.79E-06	42,823	34,652	8,703	6,086	247
7/9/2002	13	1.13E-06	1.19E-06	41,298	34,652	8,548	5,079	41
7/10/2002	17	6.13E-07	6.04E-07	43,595	34,652	8,760	7,240	137
7/10/2002	18	3.16E-07	2.73E-07	43,033	34,652	8,727	6,717	313
7/12/2002	13	2.00E-07	2.11E-07	40,615	34,701	8,417	4,952	47
7/11/2002	15	1.68E-07	1.79E-07	41,740	34,652	8,583	6,020	31
7/11/2002	16	1.03E-07	1.05E-07	42,126	34,652	8,623	6,439	88
7/10/2002	19	3.25E-08	2.61E-08	41,861	34,652	8,605	6,184	394
7/12/2002	18	2.89E-08	2.27E-08	41,280	34,701	8,537	5,635	414
7/9/2002	19	2.05E-08	1.79E-08	41,377	34,652	8,558	5,979	279
7/11/2002	17	1.70E-08	1.63E-08	41,763	34,652	8,591	6,492	165
7/18/2002	15	1.66E-08	1.52E-08	37,900	34,713	7,666	3,443	225
7/10/2002	12	5.90E-09	6.36E-09	40,889	34,652	8,485	6,122	27
7/8/2002	16	5.52E-09	5.43E-09	40,188	34,652	8,306	5,509	134
7/18/2002	14	4.64E-09	4.55E-09	37,263	34,713	7,455	3,415	138
7/8/2002	17	3.45E-09	3.09E-09	40,253	34,652	8,313	5,569	245
7/18/2002	16	2.97E-09	2.53E-09	37,968	34,713	7,697	3,820	303
8/13/2002	16	2.30E-09	1.74E-09	42,168	35,180	8,625	6,581	445
7/11/2002	14	2.09E-09	2.27E-09	41,086	34,652	8,502	6,556	20
8/12/2002	17	1.51E-09	1.14E-09	42,827	35,180	8,707	7,255	447
8/12/2002	16	1.32E-09	1.08E-09	43,014	35,180	8,720	7,562	346
7/12/2002	12	9.99E-10	1.03E-09	39,446	34,701	8,141	5,338	85
7/8/2002	15	9.87E-10	1.03E-09	39,594	34,652	8,170	5,527	64
7/9/2002	20	9.83E-10	7.98E-10	39,820	34,652	8,224	5,407	357
7/9/2002	12	9.37E-10	1.00E-09	39,727	34,652	8,218	5,655	33
8/13/2002	17	8.58E-10	5.97E-10	41,820	35,180	8,603	6,399	531
7/11/2002	18	8.26E-10	7.63E-10	40,889	34,652	8,482	6,411	204
7/10/2002	20	6.67E-10	5.01E-10	40,568	34,652	8,413	5,974	438

Table A-5. Imperfect Hydro Dispatch 2003: Top 40 Hours

date	hour	target lolp	final lolp	load	base system cap	hydro	imports	wind
7/17/2003	17	5.70E-05	5.42E-05	44,467	36,873	7,904	7,589	295
7/17/2003	15	4.92E-05	5.00E-05	44,355	36,873	8,032	7,523	175
9/4/2003	15	2.83E-05	3.13E-05	42,968	37,078	7,361	6,970	24
7/17/2003	16	2.24E-05	2.25E-05	44,846	36,873	8,643	7,658	201
7/21/2003	15	2.03E-05	1.89E-05	44,510	36,873	7,948	7,926	328
7/14/2003	18	8.39E-06	7.77E-06	43,952	36,873	7,608	8,007	333
7/23/2003	16	8.21E-06	8.92E-06	42,714	36,873	7,849	6,801	67
7/21/2003	16	7.70E-06	6.84E-06	44,929	36,873	8,562	7,988	404
9/4/2003	17	3.93E-06	4.35E-06	43,137	37,078	7,983	7,179	38
7/17/2003	18	3.38E-06	3.40E-06	43,520	36,873	8,572	7,051	196
9/4/2003	16	2.45E-06	2.75E-06	43,613	37,078	8,434	7,376	20
7/16/2003	16	2.04E-06	2.11E-06	43,431	36,873	7,899	7,838	156
7/21/2003	17	1.88E-06	1.56E-06	44,681	36,873	8,653	8,010	507
7/16/2003	18	1.57E-06	1.59E-06	43,231	36,873	7,818	7,775	185
7/14/2003	16	1.42E-06	1.34E-06	44,283	36,873	8,835	7,726	300
7/17/2003	11	1.20E-06	1.34E-06	39,009	36,873	5,248	6,367	26
7/17/2003	14	1.14E-06	1.22E-06	43,328	36,873	8,607	7,276	94
7/23/2003	15	1.13E-06	1.28E-06	42,299	36,873	8,137	6,796	16
7/17/2003	12	1.04E-06	1.16E-06	40,841	36,873	6,722	6,762	34
7/23/2003	14	8.44E-07	9.53E-07	41,536	36,873	7,373	6,888	17
7/16/2003	21	6.72E-07	6.78E-07	40,628	36,873	6,460	6,791	190
7/16/2003	17	6.54E-07	6.74E-07	43,696	36,873	8,558	7,797	162
7/14/2003	17	6.23E-07	5.94E-07	44,556	36,873	8,805	8,306	281
7/23/2003	17	5.88E-07	5.96E-07	42,412	36,873	8,306	6,775	185
7/16/2003	14	5.16E-07	5.71E-07	42,192	36,873	7,747	7,287	52
7/15/2003	17	4.68E-07	4.44E-07	43,541	36,873	7,804	8,377	284
7/24/2003	16	3.67E-07	4.00E-07	43,255	36,873	8,601	7,577	75
9/3/2003	15	3.65E-07	3.89E-07	41,953	37,078	6,818	7,840	109
9/2/2003	13	3.47E-07	3.89E-07	40,170	37,078	5,912	7,059	29
7/22/2003	14	3.20E-07	3.31E-07	40,986	36,873	7,245	6,630	151
7/22/2003	15	2.96E-07	2.99E-07	41,666	36,873	8,026	6,515	188
7/24/2003	17	2.80E-07	2.83E-07	43,180	36,873	8,665	7,403	192
9/4/2003	14	2.45E-07	2.77E-07	41,951	37,078	8,124	6,742	20
7/14/2003	15	2.43E-07	2.28E-07	43,340	36,873	8,370	7,787	305
7/16/2003	15	2.14E-07	2.21E-07	43,017	36,873	8,463	7,555	159
7/21/2003	14	2.13E-07	2.06E-07	43,431	36,873	8,603	7,737	253
9/2/2003	15	2.13E-07	2.40E-07	43,127	37,078	7,577	8,503	24
7/22/2003	18	1.75E-07	1.34E-07	41,033	36,873	7,543	6,112	599
7/17/2003	19	1.65E-07	1.60E-07	41,949	36,873	7,990	6,947	249
7/17/2003	13	1.56E-07	1.75E-07	41,954	36,873	7,886	7,289	34

Table A-6. Perfect Hydro Dispatch 2003: Top 40 Hours

date	hour	target lolp	final lolp	load	base system cap	hydro	imports	wind
7/17/2003	16	1.29E-05	1.30E-05	44,846	36,873	8,835	7,658	201
7/17/2003	15	6.52E-06	6.67E-06	44,355	36,873	8,738	7,523	175
7/17/2003	17	5.01E-06	4.77E-06	44,467	36,873	8,752	7,589	295
7/17/2003	18	2.89E-06	2.92E-06	43,520	36,873	8,623	7,051	196
7/21/2003	16	2.39E-06	2.12E-06	44,929	36,873	8,949	7,988	404
7/14/2003	16	2.04E-06	1.93E-06	44,283	36,873	8,720	7,726	300
7/21/2003	15	1.79E-06	1.67E-06	44,510	36,873	8,760	7,926	328
7/23/2003	16	1.37E-06	1.50E-06	42,714	36,873	8,436	6,801	67
9/4/2003	16	1.24E-06	1.40E-06	43,613	37,078	8,653	7,376	20
7/21/2003	17	1.16E-06	9.68E-07	44,681	36,873	8,805	8,010	507
7/17/2003	14	1.15E-06	1.24E-06	43,328	36,873	8,603	7,276	94
9/4/2003	15	9.39E-07	1.06E-06	42,968	37,078	8,497	6,970	24
7/14/2003	17	6.89E-07	6.61E-07	44,556	36,873	8,774	8,306	281
9/4/2003	17	6.41E-07	7.17E-07	43,137	37,078	8,562	7,179	38
7/23/2003	15	6.19E-07	7.05E-07	42,299	36,873	8,325	6,796	16
7/23/2003	17	5.05E-07	5.15E-07	42,412	36,873	8,353	6,775	185
7/16/2003	17	4.40E-07	4.56E-07	43,696	36,873	8,680	7,797	162
7/22/2003	17	4.27E-07	3.61E-07	41,926	36,873	8,179	6,231	468
7/24/2003	16	3.79E-07	4.16E-07	43,255	36,873	8,591	7,577	75
7/24/2003	17	3.76E-07	3.82E-07	43,180	36,873	8,576	7,403	192
7/22/2003	16	3.48E-07	3.30E-07	42,096	36,873	8,256	6,558	296
7/14/2003	18	2.66E-07	2.46E-07	43,952	36,873	8,707	8,007	333
7/22/2003	15	2.12E-07	2.16E-07	41,666	36,873	8,126	6,515	188
7/21/2003	14	2.07E-07	2.02E-07	43,431	36,873	8,611	7,737	253
7/16/2003	16	1.99E-07	2.07E-07	43,431	36,873	8,619	7,838	156
9/4/2003	14	1.94E-07	2.21E-07	41,951	37,078	8,194	6,742	20
7/16/2003	15	1.82E-07	1.89E-07	43,017	36,873	8,511	7,555	159
7/24/2003	15	1.62E-07	1.81E-07	42,643	36,873	8,417	7,416	53
7/16/2003	18	1.28E-07	1.31E-07	43,231	36,873	8,583	7,775	185
7/14/2003	15	1.10E-07	1.03E-07	43,340	36,873	8,605	7,787	305
7/21/2003	18	9.23E-08	7.17E-08	43,602	36,873	8,643	7,787	580
7/17/2003	19	8.41E-08	8.21E-08	41,949	36,873	8,188	6,947	249
7/16/2003	14	7.90E-08	8.86E-08	42,192	36,873	8,306	7,287	52
7/23/2003	14	7.74E-08	8.89E-08	41,536	36,873	8,090	6,888	17
7/16/2003	19	7.69E-08	7.90E-08	42,129	36,873	8,279	7,136	175
9/4/2003	13	6.11E-08	7.02E-08	40,352	37,078	7,757	5,920	17
7/17/2003	13	5.13E-08	5.82E-08	41,954	36,873	8,208	7,289	34
7/24/2003	18	4.03E-08	3.75E-08	42,067	36,873	8,240	7,159	314
7/22/2003	18	3.90E-08	2.97E-08	41,033	36,873	7,977	6,112	599
7/16/2003	20	3.71E-08	3.71E-08	40,917	36,873	7,916	6,455	215

Table A-7. Imperfect Hydro Dispatch 2003: Top 40 Hours
Forced Outage Rate Set to 5 Percent

date	hour	target lolp	final lolp	load	base system cap	hydro	imports	wind
7/17/2003	17	3.22E-08	3.02E-08	44,467	36,873	7,904	7,589	295
7/17/2003	15	2.61E-08	2.68E-08	44,355	36,873	8,032	7,523	175
9/4/2003	15	1.18E-08	1.36E-08	42,968	37,078	7,361	6,970	24
7/17/2003	16	8.57E-09	8.64E-09	44,846	36,873	8,643	7,658	201
7/21/2003	15	7.41E-09	6.72E-09	44,510	36,873	7,948	7,926	328
7/14/2003	18	2.12E-09	1.91E-09	43,952	36,873	7,608	8,007	333
7/23/2003	16	2.06E-09	2.33E-09	42,714	36,873	7,849	6,801	67
7/21/2003	16	1.88E-09	1.59E-09	44,929	36,873	8,562	7,988	404
9/4/2003	17	7.15E-10	8.28E-10	43,137	37,078	7,983	7,179	38
7/17/2003	18	5.85E-10	5.92E-10	43,520	36,873	8,572	7,051	196
9/4/2003	16	3.67E-10	4.33E-10	43,613	37,078	8,434	7,376	20
7/16/2003	16	2.87E-10	3.01E-10	43,431	36,873	7,899	7,838	156
7/21/2003	17	2.55E-10	1.96E-10	44,681	36,873	8,653	8,010	507
7/16/2003	18	1.97E-10	2.02E-10	43,231	36,873	7,818	7,775	185
7/14/2003	16	1.72E-10	1.58E-10	44,283	36,873	8,835	7,726	300
7/17/2003	11	1.35E-10	1.59E-10	39,009	36,873	5,248	6,367	26
7/17/2003	14	1.25E-10	1.39E-10	43,328	36,873	8,607	7,276	94
7/23/2003	15	1.24E-10	1.48E-10	42,299	36,873	8,137	6,796	16
7/17/2003	12	1.10E-10	1.29E-10	40,841	36,873	6,722	6,762	34
7/23/2003	14	8.21E-11	9.79E-11	41,536	36,873	7,373	6,888	17
7/16/2003	21	5.94E-11	6.05E-11	40,628	36,873	6,460	6,791	190
7/16/2003	17	5.72E-11	5.99E-11	43,696	36,873	8,558	7,797	162
7/14/2003	17	5.34E-11	5.01E-11	44,556	36,873	8,805	8,306	281
7/23/2003	17	4.92E-11	5.03E-11	42,412	36,873	8,306	6,775	185
7/16/2003	14	4.09E-11	4.74E-11	42,192	36,873	7,747	7,287	52
7/15/2003	17	3.56E-11	3.32E-11	43,541	36,873	7,804	8,377	284
7/24/2003	16	2.52E-11	2.86E-11	43,255	36,873	8,601	7,577	75
9/3/2003	15	2.47E-11	2.71E-11	41,953	37,078	6,818	7,840	109
9/2/2003	13	2.29E-11	2.71E-11	40,170	37,078	5,912	7,059	29
7/22/2003	14	2.07E-11	2.19E-11	40,986	36,873	7,245	6,630	151
7/22/2003	15	1.86E-11	1.90E-11	41,666	36,873	8,026	6,515	188
7/24/2003	17	1.72E-11	1.75E-11	43,180	36,873	8,665	7,403	192
7/14/2003	15	1.41E-11	1.29E-11	43,340	36,873	8,370	7,787	305
9/4/2003	14	1.40E-11	1.67E-11	41,951	37,078	8,124	6,742	20
7/16/2003	15	1.18E-11	1.23E-11	43,017	36,873	8,463	7,555	159
7/21/2003	14	1.16E-11	1.12E-11	43,431	36,873	8,603	7,737	253
9/2/2003	15	1.15E-11	1.36E-11	43,127	37,078	7,577	8,503	24
7/22/2003	18	8.79E-12	6.04E-12	41,033	36,873	7,543	6,112	599
7/17/2003	19	8.14E-12	7.83E-12	41,949	36,873	7,990	6,947	249
7/17/2003	13	7.47E-12	8.83E-12	41,954	36,873	7,886	7,289	34

Table A-8. Perfect Hydro Dispatch 2003: Top 40 Hours
Forced Outage Rate Set to 5 Percent

date	hour	target lolp	final lolp	load	base system cap	hydro	imports	wind
7/17/2003	16	3.92E-09	3.97E-09	44,846	36,873	8,835	7,658	201
7/17/2003	15	1.48E-09	1.54E-09	44,355	36,873	8,738	7,523	175
7/17/2003	17	1.02E-09	9.55E-10	44,467	36,873	8,752	7,589	295
7/17/2003	18	4.69E-10	4.77E-10	43,520	36,873	8,623	7,051	196
7/21/2003	16	3.58E-10	3.03E-10	44,929	36,873	8,949	7,988	404
7/14/2003	16	2.86E-10	2.65E-10	44,283	36,873	8,720	7,726	300
7/21/2003	15	2.38E-10	2.15E-10	44,510	36,873	8,760	7,926	328
7/23/2003	16	1.63E-10	1.86E-10	42,714	36,873	8,436	6,801	67
9/4/2003	16	1.39E-10	1.66E-10	43,613	37,078	8,653	7,376	20
7/21/2003	17	1.29E-10	9.97E-11	44,681	36,873	8,805	8,010	507
7/17/2003	14	1.27E-10	1.42E-10	43,328	36,873	8,603	7,276	94
9/4/2003	15	9.40E-11	1.12E-10	42,968	37,078	8,497	6,970	24
7/14/2003	17	6.16E-11	5.80E-11	44,556	36,873	8,774	8,306	281
9/4/2003	17	5.47E-11	6.42E-11	43,137	37,078	8,562	7,179	38
7/23/2003	15	5.29E-11	6.36E-11	42,299	36,873	8,325	6,796	16
7/23/2003	17	3.96E-11	4.07E-11	42,412	36,873	8,353	6,775	185
7/16/2003	17	3.26E-11	3.43E-11	43,696	36,873	8,680	7,797	162
7/22/2003	17	3.13E-11	2.46E-11	41,926	36,873	8,179	6,231	468
7/24/2003	16	2.64E-11	3.01E-11	43,255	36,873	8,591	7,577	75
7/24/2003	17	2.61E-11	2.67E-11	43,180	36,873	8,576	7,403	192
7/22/2003	16	2.34E-11	2.17E-11	42,096	36,873	8,256	6,558	296
7/14/2003	18	1.60E-11	1.43E-11	43,952	36,873	8,707	8,007	333
7/22/2003	15	1.16E-11	1.19E-11	41,666	36,873	8,126	6,515	188
7/21/2003	14	1.12E-11	1.08E-11	43,431	36,873	8,611	7,737	253
7/16/2003	16	1.06E-11	1.12E-11	43,431	36,873	8,619	7,838	156
9/4/2003	14	1.00E-11	1.21E-11	41,951	37,078	8,194	6,742	20
7/16/2003	15	9.35E-12	9.86E-12	43,017	36,873	8,511	7,555	159
7/24/2003	15	7.91E-12	9.22E-12	42,643	36,873	8,417	7,416	53
7/16/2003	18	5.67E-12	5.84E-12	43,231	36,873	8,583	7,775	185
7/14/2003	15	4.56E-12	4.18E-12	43,340	36,873	8,605	7,787	305
7/21/2003	18	3.56E-12	2.49E-12	43,602	36,873	8,643	7,787	580
7/17/2003	19	3.12E-12	3.01E-12	41,949	36,873	8,188	6,947	249
7/16/2003	14	2.85E-12	3.35E-12	42,192	36,873	8,306	7,287	52
7/23/2003	14	2.77E-12	3.37E-12	41,536	36,873	8,090	6,888	17
7/16/2003	19	2.74E-12	2.85E-12	42,129	36,873	8,279	7,136	175
9/4/2003	13	1.95E-12	2.38E-12	40,352	37,078	7,757	5,920	17
7/17/2003	13	1.55E-12	1.85E-12	41,954	36,873	8,208	7,289	34
7/24/2003	18	1.09E-12	9.90E-13	42,067	36,873	8,240	7,159	314
7/22/2003	18	1.05E-12	7.10E-13	41,033	36,873	7,977	6,112	599
7/16/2003	20	9.75E-13	9.75E-13	40,917	36,873	7,916	6,455	215